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Society of Petroleum Engineers
Distinguished Lecturer Program
www.spe.org/dl
Production Optimisation of Conventional & Unconventional Wells with ESP Real Time Data

Lawrence CAMILLERI
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Artificial Lift Domain Head
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Unconventional Well Case Studies:

• Additional case studies for unconventional wells are not included in this slide deck, however they can be viewed via skype upon request to the author, who can be reached at lcamilleri@slb.com.

• The skype session can also enable a more detailed Q&A where required.
The Digital Transformation Is Growing Fast

**Global Digital Oilfield Market ($bn)**

- 2017: $26.31
- 2018: $27.27
- 2019: $28.54
- 2020: $30.15
- 2021: $32.22

**Enablers:**
- Declining costs of sensors and data storage
- Rapid progress in advanced analytics (e.g. machine learning)
- Greater connectivity of people and devices
- Faster & cheaper data transmission

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Why ESP Production Optimisation?

- 940,000 producing wells worldwide
- 125,000 (13%) of these wells lifted by ESP
- More than 54% of artificial lift global spend is on ESP (4.8 B$ out of 8.8B$ in 2017) with all other types representing less than 23% each.
- More than 30% of production lifted by ESP as it is the lift type with the highest rate

➔ ESP optimization has the biggest impact on both production and AL expenditure
## Operator’s View

<table>
<thead>
<tr>
<th>BP</th>
<th>Rossneft</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Technology Outlook: 2015</strong></td>
<td><strong>SPE 112238, Real Time Optimisation Approach for 15,000 ESP Wells</strong></td>
</tr>
<tr>
<td>BP Believes that digital technologies can deliver</td>
<td>▪ “Calculations showed economical efficiency of system implementation on 7451 wells out of over 11,000 working ESP wells, with possible annual oil production increase of 11 million bbls.”</td>
</tr>
<tr>
<td>• 4% Production Enhancement</td>
<td>▪ This justified the investment of 6400 US$ per well in automation hardware i.e. Variable Speed Drive, Gauges and real time data transmission</td>
</tr>
<tr>
<td>• 13% Cost Savings</td>
<td>▪ <strong>The first step is identifying the well max. potential</strong></td>
</tr>
<tr>
<td></td>
<td>▪ What is the actual IPR curve? Pr and PI?</td>
</tr>
<tr>
<td></td>
<td>▪ What could be the PI after possible stimulation?</td>
</tr>
</tbody>
</table>
**Agenda**

### Commonly Available ESP Real Time Data

1. Frequency
2. Current
3. Voltage
4. Tubing Head Pressure
5. Pump Discharge Pressure
6. $P_i = \text{Intake Pressure}$
7. $T_i = \text{Intake Temperature}$
8. $T_m = \text{Motor Temperature}$

### VALUE OBJECTIVES

1. Uptime
2. Run Life
3. Power Consumption
4. Production Enhancement

---

**Generic Concepts:**

- Gauge metrology
- Data visualization
- Slow & Fast Loop
- Data to Value Chain
- The importance of high frequency flowrate in addition to pressure data
ESP Gauges…mature technology

1. Reliability – MTBF >10 years
2. No need for instrument line ➔ low cost
3. Metrology of ESP gauges
   - Accuracy +/- 5 psi
   - Resolution 0.1 psi
   - Drift 5 psi / year

➔ INFLOW ANALYSIS IS POSSIBLE
Data Visualisation ➔ Solution = Multiple Tracks

**Challenge** = Large Production Sets
- 6 to 15 analogue signals per well
- 1 million points / year /signal

**Solution**
- Separate tracks for signal groups
- User defined filtering
Data to Value Chain

Data + Domain = Information

Information + Decisions = Execution

Execution = Value
How Real Time Data & Automation

Data + Domain = Information

Information → Decisions

Decisions + Proactive Execution = Maximized Value

Maximized Value + Automation = Information
The Value of Data...

Shell's Smart Fields Value Loop

**SPE 127858**

*Perdido: The First Smart Field® in the Western Hemisphere*
Robert K. Perrons, SPE, Shell International Exploration & Production

**SPE 127730**

*Multi-asset Production Support Centre—Generating Values*
Kjell Lejon and Karl Johnny Hersvik, Statoil ASA, and Arild Bæe, Epsis AS
Dedicated Field Stock:
- New replacement to well-site with 12 hours
- Dynamic to reflect future needs (not present)
- Cover the range of expected flows and heads

Set Operating Parameters:
1. Stop and Start
2. Choke
3. Frequency
4. Control Mode

Monitor Performance:
Rate, pressure, temperature

Pull Pump string

Workover Operations
(stimulation, fracking, sidetracking, reperforation)

Fast Loop
Minutes & hours

Slow Loop
Time is measured in months and in most cases years

Update of Ready Line

Design pump system

Workover Ops

ESP assembly & Commissioning

Stock is replenished via manufacturing facility

Re-specify Equipment

Carry Out failure analysis

Slow & Fast Feedback Loops – Applied to ESPs
VALUE OBJECTIVES

1. Uptime
2. Run Life
3. Power Consumption
4. Production Enhancement
The Main Causes of ESP Downtime

The main two causes are:

1. Facility shut-downs e.g. electrical power interruption.

2. ESP stops automatically triggered by the motor controller to protect the ESP from misoperation, which would otherwise lead to failure. The main types are:
   - **Deadheading**: Usually caused by inadvertent valve closure
   - **Pump-Off**: Loss of submergence caused by pump rate greater than inflow potential
   - **Gas Lock**: Performance is degraded by large volumes of free gas, which initially leads to low flowrate events.
Improving Uptime with **FAST LOOP** – **Gas Lock**

<table>
<thead>
<tr>
<th>Uptime</th>
<th>All shutdowns eliminated for 300 days (previously 1 shutdown per day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>74%</td>
<td>Intake Pressure Stabilised</td>
</tr>
<tr>
<td></td>
<td>Constant Current Achieved</td>
</tr>
<tr>
<td></td>
<td>Frequency Varied Automatically</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Domain &amp; Algorithm Sets</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Target Current</td>
</tr>
<tr>
<td>- Underload delay</td>
</tr>
<tr>
<td>- Low Frequency Setting</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Data Current</th>
</tr>
</thead>
<tbody>
<tr>
<td>Execution</td>
</tr>
<tr>
<td>Frequency Variation</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Value</th>
<th>Eliminate All Trips</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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</tr>
</tbody>
</table>

Intake Pressure Stabilised
Constant Current Achieved
Frequency Varied Automatically

**Uptime 74%**
All shutdowns eliminated for 300 days (previously 1 shutdown per day)

Nov          Dec         Jan         Feb

Value Eliminate All Trips

Execution Frequency Variation

Domain & Algorithm Sets
- Target Current
- Underload delay
- Low Frequency Setting

Data Current

 Courtesy of SPE-190940-MS; Tuning VSDs in ESP Wells to Optimize Oil Production—Case Studies
Gas Lock Protection

- Period with no flow to wellhead
- Current Increasing
- Gas Lock Current = 20 A
- Underload Trip Setting 15 A
• Operating point relative to BEP has an impact on pump gas handling (SPE 163048)

• PCL pump flowrate is higher and the difference with measured rate provides a measure of gas degradation.

• PCL provides confirmation that transient downhole pump rate reaches zero rate when in gas lock mode.

• When frequency is increased, there is a step decrease in discharge pressure, this is due to gas degradation.

• PHI provides advanced warning of gas degradation, which is not detected by discharge pressure, which also provides an alarm as to when flowrate calculation overestimates rate.

• Frequency can be tuned to eliminate severe gas degradation.

• Also in constant current mode, when frequency is not “flat toping”, PHI is 1.0, thereby confirming gas degradation is quasi eliminated. When PHI is ~1.5, there is severe gas degradation.
• PCL provides confirmation that transient downhole pump rate reaches zero rate when in gas lock mode.

• While this is OK occasionally to avoid a gas lock trip and motor overheating, the frequency of these events is high and causing additional stress to the ESP.

No “flat Toping” = current target reached = PHI=1.0

“flat toping” = current target not reached = PHI = 1.5
Increased Gas Degradation at Operating Point $< \text{BEP}$

**Multiple Stages – Schlumberger Test**
Less severe as the GVF is lower closer to discharge of pump as gas is compressed

**Single Stage – Tulsa University**
Challenge: Low PI well with some gas tripping on underload causing downtime.

Solution
Constant intake pressure feedback mode ➔ maintains drawdown and avoids tripping.
Improving Uptime with **SLOW Loop**

Production Increased by 250 sm3/day

Wellhead Pressure indicates Severe Slugging

Stabilized

At Workover Helico-Axial Pump Installed

SPE 141668; Helicoaxial Pump Gas Handling Technology: A Case Study of Three ESP Wells in the Congo
Dedicated Field Stock:
- New replacement to well-site with 12 hours
- Dynamic to reflect future needs (not present)
- Cover the range of expected flows and heads

Set Operating Parameters:
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Stock is replenished via manufacturing facility

Re-specify Equipment

Carry Out failure analysis

24
VALUE OBJECTIVES

1. Uptime
2. Run Life
3. Power Consumption
4. Production Enhancement
Measure, Classify and Record…. ➔ Slow Loop

- Run life improvement requires continuous monitoring and failure analysis in the slow loop i.e. years as opposed to minutes

- “Classification” is a key enabler

- This principle can also be applied to:
  - Uptime Improvement
  - Power Optimisation
  - Production Enhancement

“Implementation of a comprehensive monitoring and failure investigation system was essential in the optimization of North Kaybob ESP Performance” SPE 19379 – ESP Improving Run Lives in the North Kaybob BHL Unit No 1, by C.G. Bowen and R.J Kennedy, Chevron Canada Resources.
Example of surveillance on a platform with 5 wells

Database of stress creating events

Recording & **Classification**

Identify Deadheads as recurring event

Investigate root cause & implement remedial action

---

**Pump Off, 5**

**Low Flow, 2**

**Deadhead, 16**
Run-Life Improvement powered by data

**FAST LOOP:** Infant Mortality
Half Year Survivability Improved from 78% to 85%

**SLOW LOOP:**
Five-year Survivability Improved from 15% to 30%

MTBF (mean time between failure) Increased from 2 to 3.5
Years between 2006 & 2014
This study shows that reducing the number of stop/starts not only improves uptime/production but also improves run life.
Run Life – Recommended Measurement Technique

- Survival Analysis considers pumps still running ➔ leading indicator
- Kaplan Meier Presentation removes dependency on changing demography.
- Exponential fit assumes constant survival rate, which is useful as one can identify populations above and below the average.

This mathematical model is based on a constant survival rate. (a.k.a. single parameter Weibul Model).

Convenient as it allows the user to identify, which groups of pumps have a higher or lower than average run life. Also easy to integrate and manipulate in excel as

\[ R(t) = e^{-t/MTBF} \]

\[ MTBF = \int_0^\infty e^{-t/MTBF} dt \]
Illustration of Shape factor “b”

If it is not possible to model using a classic exponential function which assumes a constant failure rate. A shape factor is required (=b), which is also known as a 2 parameter Weibull function.

$$R(t) = e^{-\left(\frac{t}{a}\right)^b}$$

$$\int_0^\infty e^{-ax^b} dx = \frac{1}{b} a^{-\frac{1}{b}} \Gamma \left( \frac{1}{b} \right)$$

- All these survival curves have the same MTBF, chosen arbitrarily as 8 years to illustrate the shape factor concept.
- Low shape factor will have increased infant mortality.
- High shape factor will have reduced infant mortality.
Types of Analysis that can be performed

- Time lapsed to monitor evolution of run life
- Comparing population sub-sets to identify cause of reduced overall run life

Time Lapsed Analysis shows improvement in MTBF

<table>
<thead>
<tr>
<th>Type of Motor</th>
<th>MTBF (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Section Motor in Low Temperature (~50 to 75 °C)</td>
<td>4.9</td>
</tr>
<tr>
<td>All Wells</td>
<td>3.2</td>
</tr>
<tr>
<td>Tandem Section Motor in Higher BHT (~100 °C)</td>
<td>2.4</td>
</tr>
</tbody>
</table>

Comparing Population Types; Here we prove that temperature impacts average run life but has a reduced effect on infant mortality.
**VALUE OBJECTIVES**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Uptime</td>
</tr>
<tr>
<td>2.</td>
<td>Run Life</td>
</tr>
<tr>
<td>3.</td>
<td><strong>Power Consumption</strong></td>
</tr>
<tr>
<td>4.</td>
<td>Production Enhancement</td>
</tr>
</tbody>
</table>
Power Optimisation ➔ Minimise PF x EFF

\[ \text{Power} = \frac{V \times I \times PF \times EFF \times \sqrt{3}}{746} \]

<table>
<thead>
<tr>
<th>V</th>
<th>Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>Current</td>
</tr>
<tr>
<td>PF</td>
<td>Power Factor</td>
</tr>
<tr>
<td>EFF</td>
<td>Efficiency</td>
</tr>
</tbody>
</table>

The power equation shows that for a given pump load, when the \((PF \times EFF)\) is maximized, the current is minimized.

➔ Minimise Power consumption
➔ Minimise Motor Temperature, which maximises run life

This is achieved by controlling voltage

Voltage 100% (Voltage Range from 0.7 to 1.2 of nominal)
ESP Power Optimisation ➔ Double Benefit

Reduction in voltage:
- 38% power saving (156 KVA vs 248 KVA)
- Run Life Increase
  - Motor Temperature reduction
  - Motor Voltage reduction

Achieved without any loss in production
Cost Reduction – Field Wide Energy Saving Examples

- 24 wells
- Total Power Cost = 2.4M$ / month
- Saving = 380k$/month = 14%

- Industry pay-back period on energy savings is between 0.8 & 1.2 years with savings of 30 M$ in 2010 (source IAC 2017)
- For ESP wells, the pay-back period is zero as real time data is available anyway
Stress Caused by Temperature & Voltage

**Effect of Conductor Temperature**

Arrhenius Law

\[ L = A \exp \left( \frac{B}{T} \right) \]

- \( L \) = life
- \( T \) = temperature
- \( A,B \) = constants

**Effect of Voltage**

\[ L = (E)^n + C \]

- \( L \) = expected life (time)
- \( E \) = applied electrical stress
<table>
<thead>
<tr>
<th>VALUE OBJECTIVES</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Uptime</td>
</tr>
<tr>
<td>2. Run Life</td>
</tr>
<tr>
<td>3. Power</td>
</tr>
<tr>
<td>Consumption</td>
</tr>
<tr>
<td>4. Production</td>
</tr>
<tr>
<td>Enhancement</td>
</tr>
</tbody>
</table>
The Value of High Frequency Flowrate & Pressure

Without Build-ups

Downhole Measurement with:
- High Frequency
- High Resolution
- High Repeatability

Liquid Rate
Pressure

IPR on the fly
PTA in drawdown
Skin and depletion evolution
Reservoir Flow regime (e.g. Fractures)
Reserves & Drainage area evolution

Without Build-ups

Fast Loop
Slow Loop
Flowrate trends....

- High frequency
- High resolution
- High repeatability

Discernible Trend

Accuracy not required for a trend

<table>
<thead>
<tr>
<th></th>
<th>Liquid rate from test separator</th>
<th>Calculated using real time data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency</td>
<td>1/month</td>
<td>1/min</td>
</tr>
<tr>
<td>Accuracy</td>
<td>±5%</td>
<td>same</td>
</tr>
<tr>
<td>Resolution</td>
<td>?</td>
<td>&lt;100 bbl/d</td>
</tr>
<tr>
<td>Repeatability</td>
<td>Poor</td>
<td>HIGH</td>
</tr>
<tr>
<td>Discernible Trend</td>
<td>NO</td>
<td>YES</td>
</tr>
</tbody>
</table>
One Possible Method …

- **High frequency**
- **High resolution**
- **High repeatability**

**No need for additional hardware**

1. Proven from first principles ➔ Always true
2. Equation is density independent:
   - Valid with changing WC
   - Can handle phase segregation
3. Analytical equation ➔ derivative provides resolution
4. Type Curve ➔ Shape does not change with calibration.
5. Valid across the full range of the pump curve irrespective of pump type.

\[
\frac{(P_d - P_i) \times Q_p}{58847 \times \eta_p} = V \times I \times PF \times EFF \times \sqrt{3}
\]
IPR on the fly without build-ups

Small changes in frequency and wellhead pressure provide multi-rate test opportunities

Enabled by flowrate and pressure with:
- High frequency = 1/min
- High resolution = <20 rbpd
- High repeatability

SPE paper 183337
**TIME LAPSED ANALYSIS**

1. **PI increase ➔ no skin increase**

2. Depletion is circa 145 psi over this 14 month period using SIP technique
PTA (Pressure Transient Analysis) in drawdown

**Problem Statement:**
- PTA has a huge value for skin and boundary characterization, however traditionally requires build-ups due to lack of downhole transient rate.
- However build-ups are associated with production deferment.
- Also build-ups are rarely long enough to see boundaries.

**The challenge:** Drawdown PTA is mathematically equivalent to build-ups, however presents the following challenges:
- Requires transient flowrate
- High resolution ESP gauges ➔ Noisy derivative
- Slugging wells

**The Solution:**
- Virtual flowmetering can provide downhole flowrate with high frequency and resolution
- As flowrate is measured at the same point as pressure, there is no time lag between flow and pressure measurements.
- Superposition time is enabled and provides natural smoothing
- Drawdown means that one can wait to see boundary conditions.
A common Problem

Derivative is too noisy in drawdown to identify IARF

Log-Log plot: \( (p-p@dt=0) \cdot Q/[q_n-q_{n-1}] \) and derivative [psi] vs dt [hr]
IARF identified using semi-log with Superposition time

Obtain history match and measure:
- Skin
- Distance to constant pressure boundary

\[ S_n(\Delta t) = \sum_{i=1}^{n} q_i - q_{i-1} \left( \log \left( \sum_{j=1}^{n} \Delta t_j - \Delta t \right) - \log \Delta t \right) \]
Why Skin is independent of absolute rate

- As absolute rate changes, permeability changes linearly with rate (m), but skin does not change!
- Skin is independent of rate accuracy and only dependent on rate trend.

\[ \Delta p_{ws}(\Delta t) = \frac{162.6q_n B \mu}{kh} \left[ Sn(\Delta t) + \log \left( \frac{k}{\Phi \mu c r_w^2} \right) - 3.228 + 0.8686S \right] \]

\[ Sn(\Delta t) = \sum_{i=1}^{n-1} \frac{q_i - q_{i-1}}{q_n - q_{n-1}} \left( \log \left( \sum_{j=1}^{n-1} \Delta t_j - \Delta t \right) - \log \Delta t \right) \]

This is summarized in the table below:

<table>
<thead>
<tr>
<th>Storage &amp; Skin</th>
<th>Permeability</th>
<th>Boundary</th>
</tr>
</thead>
<tbody>
<tr>
<td>C</td>
<td>Skin</td>
<td>k.h</td>
</tr>
<tr>
<td>( r_w \uparrow 10%</td>
<td>-</td>
<td>↑ 0.1</td>
</tr>
<tr>
<td>( \phi \uparrow 10%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>( c_1 \uparrow 10%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>( \mu \uparrow 10%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>( h \uparrow 10%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>( q.B \uparrow 10%</td>
<td>↑ 10%</td>
<td>-</td>
</tr>
</tbody>
</table>
Measuring Skin with Drawdown

Example from SPE paper 185144 shows how rate data enables use of semi-log. This enables correct identification of IARF (Infinite Acting Radial Flow) and therefore skin measurement.

- High frequency
- High resolution
- High repeatability

Skin = intercept / slope = 6.4
The value of stimulation

Even where WC (Water Cut) is high and the absolute rate is relatively low, the value of skin remediation is high

<table>
<thead>
<tr>
<th></th>
<th>Before Stimulation</th>
<th>After Stimulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Skin</td>
<td>6.4</td>
<td>0</td>
</tr>
<tr>
<td>PI</td>
<td>1.31 BPD/psi</td>
<td>2.21 BPD/psi</td>
</tr>
<tr>
<td>Pwf</td>
<td>740 psia</td>
<td></td>
</tr>
<tr>
<td>Liquid Rate</td>
<td>1232 BPD</td>
<td>2089 BPD</td>
</tr>
<tr>
<td>Incremental Liquid Rate</td>
<td>0</td>
<td>857 BPD</td>
</tr>
<tr>
<td>WC</td>
<td>95%</td>
<td>95%</td>
</tr>
<tr>
<td>Incremental Oil Rate</td>
<td>0</td>
<td>43 BOPD</td>
</tr>
<tr>
<td>Incremental Annual Revenue @ 50 US$/bbl</td>
<td>0</td>
<td>782 k$</td>
</tr>
</tbody>
</table>
Depletion & Skin Monitoring

- **Challenge:**
  - Monitor evolution of reservoir pressure & skin without build-ups.
  - Apply to wells with large number of stop/starts

- **The Solution:** History Matching but with the use of downhole flowrate which has high frequency and resolution.

- **Value Statement**
  - Find the maximum rate that the well can produce without depletion
  - Monitor evolution of drainage area static pressure and skin
  - Avoid downtime associated with build-ups.
  - Avoid the need for observation wells

### Period #1
- Depletion = 1.25 psi/day
- No skin change

### Period #2
- Depletion = 0.3 psi/day
- Skin Pressure drop 150 psi

---

![Graph showing reservoir pressure and flow rates over time.](image-url)
Before & After History Matching

Because of high frequency rate capturing transients, the match can be achieved even where the well experiences numerous shut-downs.
Flow Regime Identification

By plotting the rate normalized pressure difference versus time in log-log, Reservoir flow regimes can be identified...

- Optimise Frac Design
- Drainage Area & Reserve Estimates

Example of a MFHW (Multiple Fractured Fracked Horizontal Well courtesy of Paper URTEC #2471526)
High Frequency vs. Test Separator Flowrate

One cannot see transient fracture flow regimes with low frequency & low repeatability test separator data, even daily data is insufficient.
**BDF ➔ Reserves & PI**

Example from SPE paper 185144

\[
\frac{P_i - P_{wf}}{q} = \frac{1}{C_t \times N} t_{mb} + b_{pss}
\]

- \( t_{mb} = \frac{N_p}{q} \) = material balance time
- \( b_{pss} = \frac{1}{P_i} \) = inverse of PI for pseudo steady-state condition
- \( C_t \) = compressibility, 1/psi
- \( N \) = Pore Volume (Liquid in place), barrels

**Blasingame, T.A. and Lee, W.J., 1986, Variable-Rate Reservoir Limits testing, presented at the Permian Basin Oil & Gas Recovery Conference held in Midland, TX March 13, 1986, SPE 15028**

**PI = 0.81 bpd/psi**

**Slope = \( 1/(C_t \times N) = 0.006118 \) psi/barrels**

Test Separator does not capture BDF
HCPV (Hydrocarbon Pore Volume) & Drainage Area

- Monitor well drainage area reservoir pressure and evaluate impact of:
  - Drawdown
  - Production rates of offset wells
- In this example, HCPV is increasing, which suggests that the well recovery factor is increasing.
- Ct = compressibility
- N = HCPV
Value = Decisions

- IPR on the fly
- PTA in drawdown
- Skin and depletion evolution
- Reservoir Flow regime (e.g. Fractures)
- Reserves & Drainage area evolution

- Pump Sizing
- Drawdown Management
- Skin / Stimulation Candidates
- Water Injection Management
- Fracture Design Optimisation
- Infield Drilling Placement
Data to Information Map

Data
1. Openhole logs
2. Geological maps
3. PVT data
4. Permanent Gauges (P, T, Q, etc...)
5. Rate history
6. Cased Hole (PLT, RST)
7. Build-ups

Static, Contextual Data

Real-time Data

Digital Twins Virtual Flowmeters

Episodic Data
Data which does not stream automatically in real-time and requires intervention

Analytical Tools
- Equipment Models
- NODAL
- Pressure transient
- Rate transient
- Simulation
- Lab analysis
- Etc...

Information
1. Equipment health check
2. IPR curve
3. Skin
4. Pr trend
5. Recovery factor
6. Scale Treatment
7. Etc...

Will episodic data become a thing of the past to be replaced by high frequency data available on all wells, especially for flowrate?
Key Take-Aways

Real-Time Data drives Production Optimisation

1. **Uptime and MTBF**: Improved by identifying the cause of trips & implementing remedial action:
   - FAST LOOP = choke, pump speed and/or control settings
   - SLOW LOOP = Changing operating procedures and/or ESP design

2. **Power Optimisation**: Field average power savings of up to 20% are documented with individual case studies showing 40% saving.

3. **Production Enhancement**:
   - **Key Enabler** = high frequency / high resolution liquid rates & pressure data
   - **Value** =
     - IPR Curve on the fly ➔ Establish well potential and update on a regular basis
     - PTA – Identify skin ➔ Stimulation candidates
     - History Matching ➔ evolution of reservoir pressure & skin
     - Flow Regime ➔ fracture protocol Design
     - Monitor evolution of drainage area
Bibliography

- Camilleri, L. and MacDonald, J., 2010, How 24/7 Real-Time Surveillance Increases ESP Run Life and Uptime, SPE 134702 presented at ATCE in 2010 in Florence, Italy.
- Camilleri, L., and G. Hua, N. H. Al-Maqsseed and A. M. Al Jazzaf, 2018, Tuning VSDs in ESP Wells to Optimize Oil Production—Case Studies, SPE 190940
- Zdolnik, S., Pashali, A., Markelov, D., Volkov, M., 2008, Real Time Optimisation Approach for 15,000 ESP Wells, SPE 112238
Your Feedback is Important

Enter your section in the DL Evaluation Contest by completing the evaluation form for this presentation
Visit SPE.org/dl

Real-Time Data can truly drive Production Optimisation
BACK-UP SLIDES
UPTIME: Measurement, Diagnostic, Resolution
Automation Delivers Value

High Frequency Flowmeter

Well Model

VSD Control

Data + Digital Twin

Fast Loop

Automatic Feedback Loop

35 psia Flowing Pressure Without Pump-Off

SPE 181218
Using Liquid Inflow Method to Optimize Progressive Cavity Pumps

Increased PCP run life
Example of how uptime can be measured

Continuous measurement provides the evolution of uptime, this is made possible by high frequency real time data.

Highest Frequency of stop/start with 10 restarts in 15 days

Operational Days 514
Downtime Days 46
Uptime 91%
Number of stops 108
Stops / month 6.4

Statistically, more than 3 starts per month has a negative impact on run life (see back-up slide for explanation)
Following a shut-down there is phase segregation in the well and ESP produces nearly 100% water for the first 1.5 hours. This is corroborated by the high discharge pressure and current.

This is also seen on the intake temperature as the pump is 1600ft TVD above the top of perforations. Therefore initial measured temperature is a function of geothermal gradient and when wellbore storage is finished, then the gauge sees 100% reservoir fluid which is a few degrees hotter.

This is the pump up time. It takes approximately 30 min for the pump to reach the discharge pressure required to lift fluid to the wellhead.

Pumping 100% reservoir fluid. Discharge pressure is declining as the column becomes lighter with increasing GOR.

Free gas in the pump causes head degradation and therefore a drop in discharge pressure. This leads to a reduction in flowrate which is seen with an increase in intake pressure and a reduction in current. The pump finally trips on underload, but in any case would not have been able to lift fluid to surface as discharge pressure falls below 1500 psia.
Resolution both in the “fast” loop

- **Fast Loop Solution**
  Eliminate trips through diagnostics (aka Root Cause Analysis) and remedial action:
  - Choke setting change
  - Speed change
  - Or operating the ESP on a feedback loop using a VSD to maintain either constant current or intake pressure.
  - Or defeating traditional current underload and only shutting down on motor temperature (previously not possible before the advent of ESP gauges)

- **Slow Loop Solution**
  These observations are subsequently used in the redesign of the ESP (see example in back-up slides of addition of helicoaxial pump which eliminates slugging).
Run Life: Measurement, Diagnostic, Resolution
Tracking of “stress” events

KPI = number of critical events per well:

- This will initially rise as population grows
- Will eventually drop if root cause analysis and remedial action is performed in both fast & slow loops

Courtesy of Schlumberger Surveillance Center
Tracking of “stress” events

- Criticality drives prioritisation of:
  - Root cause analysis
  - Remedial action
- Identify recurring events
- Below is the classification suggested by SPE paper 134702 and results from surveillance of over 200 wells over a period of 6 years

**KPI = number of critical events per well:**
- This will initially rise as population grows
- Will eventually drop if root cause analysis and remedial action is performed in both fast & slow loops

### Alarms Classifications

<table>
<thead>
<tr>
<th>Classification</th>
<th>#</th>
<th>%</th>
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<tbody>
<tr>
<td><strong>CRITICAL</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deadhead - DH</td>
<td>1642</td>
<td>29%</td>
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<tr>
<td>Low Flow - LF</td>
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<tr>
<td>Pump Off - PO</td>
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<tr>
<td>Downhole Mechanical - DM</td>
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<td>Gas Lock</td>
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<td><strong>URGENT</strong></td>
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<td>20%</td>
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<td>Surface Electrical - SE</td>
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<tr>
<td>Surface Hardware - SH</td>
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<tr>
<td>Gauge Fault - GF</td>
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<tr>
<td><strong>CONCERN</strong></td>
<td>2937</td>
<td>51%</td>
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<td>Data Transmission - DT</td>
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<tr>
<td>Information - IN</td>
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<tr>
<td>Shutdown Notification - SN</td>
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<tr>
<td>Start-up Procedure - SS</td>
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<tr>
<td>Procedure Error - PE</td>
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<tr>
<td>Software - SW</td>
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<tr>
<td>Hardware - HW</td>
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<tr>
<td><strong>TOTAL from 2008 to 2015 YTD</strong></td>
<td>5712</td>
<td>100%</td>
</tr>
</tbody>
</table>

**CRITICAL** Immediate action required, ESP/well in threat.

**URGENT** No immediate threat to ESP but action required to stabilize ESP/well or improve production.

**CONCERN** No threat to ESP but resolution will improve alarming or monitoring.

Reduction as remedial action implemented

Courtesy of Schlumberger Surveillance Center
Power: Measurement, Diagnostic, Resolution
Production Enhancement

- **The main objectives are:**
  - Increase drawdown
  - Reduce skin
  - Maximise drainage area i.e. recoverable reserves

- **The levers available are:**
  - Manage drawdown (choke and pump speed)
  - Stimulate to remove skin
  - Manage pressure support e.g. water injection

- **Constraints are understanding the well potential in terms of:**
  - Inflow Performance
  - Pressure support
  - Well interference
  - Skin – formation damage
  - Reservoir size (boundaries)

**Testing is essential to:**
- **Determine well potential**
- **Take the right action (use the right lever) to increase production**
Digital Twins…

To deliver “Proactive Execution” consistently and effectively on a large scale, digital twins are indispensable

**DEFINITION** = Mathematical model which is a replica of a physical asset and is automatically and continuously updated using real time data.

**Key properties for successful digital twins:**

- Single calibration valid for long periods of time otherwise model updates are laborious & costly. This requires algorithms which have self calibration features e.g. Specific Gravity independent to handle changes in WC and GOR
- Valid across a wide range; therefore make maximum use of analytical models which respect physics at all times and therefore always true as opposed to correlations or artificial intelligence which are only valid once trained / calibrated.
- Avoid algorithms with iterations required to resolve unknowns as these are time consuming. There is also the risk of non-convergence.
On the fly IPR with Multirate Test, SPE 185144

- IPR is obtained on-the-fly without a build-up to measure static pressure.
- Made possible by liquid rate with high frequency, high resolution and high repeatability.
- Difficult with test separator data.

PI = 14 rbdps/psi
Pr = 1856 psia
Digital Twin provides

A. Real time High Frequency Flowrate
B. Real Time ESP Management
   - Health Monitoring
   - Operating Point
   - Power Optimisation

Engine is located in the cloud with the following advantages:
- Collaborative workspace.
- Can interface any data historian.
- Cost of engine maintenance is shared by multiple users.
PHI* - Pump Health Indicator

Identify degradation **WITHOUT:**
- Without flowrate
- Use commonly available real-time data

**Enables:**
- Monitor Pump Health in Real Time
- Calibrate Flowrate Models where well tests is not available for calibration
Compares actual measured differential head to theoretical factory curve head at a given flowrate…usually the production test rate. This method requires knowledge of:

1) Rates
2) Fluid ➔ SG
3) PVT

Not Available without a well test
The Alternative Reference Curve

- Typically this is the factory water test curve
- But can be an in-situ curve based on flowrate measurement

\[ \frac{DP_r}{P_r} = f(DP) \]

- \( DP_r \) independent
- \( P_r \) dependent

\( DP \) = Pump Differential Pressure (psi)

\( \text{Flowrate (bpd)} \)

\( \text{DP} = \text{Pump Differential Pressure (psi)} \)

Conventional **WITH** Flowrate

NEW **WITHOUT** Flowrate
Examples of Flowrate Independent Characteristic Curves
PHI has two modes

\[
PHI = \frac{\frac{DP}{P}_{\text{actual}}}{\frac{DP}{P}_{\text{reference}}} = \frac{C_\eta}{C_q}
\]

- \( C_\eta = \frac{\eta_a}{\eta_r} \) Efficiency Degradation
- \( C_q = \frac{Q_a}{Q_r} \) Flow Degradation
- \( DP = P_d - Pi \) Pump Differential Pressure
- \( P \) Pump Absorbed Power

**Mode #1:** Provides identification of change in pump performance change independently of flowrate due to:
- Wear
- Gas Degradation
- Viscosity Degradation

**Mode #2:** For a few weeks following ESP start-up:
- Pump is new \( \Rightarrow \) no wear
- Based on PVT \( \Rightarrow \) No Viscosity degradation
- High intake pressure, GOR \( \sim \) Rs \( \Rightarrow \) no gas degradation

PHI = 1.0 Calibration
PHI Example, SPE paper 176780

PHI over 16 months

PHI zoom-in on last 5 days

Insulation Degradation predicting Motor Burn

PHI = \left( \frac{\text{Actual}}{\text{Reference}} \right) = C_3

PHI = 1.0 \rightarrow \text{good condition}
Calibration Achieves Rate Accuracy < 2.5%

- Following ESP start-up initial calibration based on PHI (Pump Health Indicator) =1.0 as
  - Pump is new ➔ no wear
  - Based on PVT ➔ No Viscosity or gas degradation
- If PHI remains constant at 1.0 ➔ calibration is maintained.
- Verified against well tests & accuracy achieved
  - SPE 183337: Accuracy <2.5%
  - SPE 2471526: Accuracy < 1%

\[
\text{PHI} = \frac{\left( \frac{\text{DP}}{\text{P}} \right)_{\text{actual}}}{\left( \frac{\text{DP}}{\text{P}} \right)_{\text{reference}}} = \frac{C_\eta}{C_q}
\]

- \(C_\eta = \frac{\eta_a}{\eta_r}\) Efficiency Degradation
- \(C_q = \frac{Q_a}{Q_r}\) Flow Degradation
- \(\text{DP} = \text{Pd-Pi}\) Pump Differential Pressure
- \(\text{P}\) Pump Absorbed Power

Actual matched to Reference (pump curve) to achieve PHI=1.0

Calibrated downhole liquid rate

Well test results

PHI = 1.0 ➔ Liquid Rate model calibrated

Courtesy of SPE-183337 - Testing the Untestable... Delivering Flowrate Measurements with High Accuracy on a Remote ESP Well
PHI = 1.0, liquid rate & WC are calibrated

Rise in PHI detects pump mechanical wear after prolonged operation in downthrust in sandy environment

Pump Operating in downthrust in sandy environment cause of wear

Intake pressure rising with drop in production